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Attachment A
Greenhouse Gas Emissions Reduction Measures For the Electricity and Natural Gas Sectors Under Consideration as Part of R.06-04-009

1. Background and Introduction

The staff of the California Public Utilities Commission (Public Utilities Commission) prepared this paper to assist the development of strategies for reducing greenhouse gas (GHG) emissions occurring in the electricity and natural gas sectors. This effort is being undertaken at the Public Utilities Commission in Rulemaking (R.) 06-04-009 and in Docket 07-OIIP-01 at the California Energy Commission (Energy Commission). In these proceedings, the two Commissions will provide the California Air Resources Board (ARB) with joint policy recommendations consistent with Assembly Bill 32 (AB32) for both the natural gas and electric sectors.

ARB is charged with the responsibility for coordinating the policies under which AB32's GHG emissions targets will be achieved. In order to formulate an effective plan for meeting the emission reduction goals implied by AB32's targets, ARB will need detailed input on the origin, level, and costs of emission reductions that can be achieved within each sector before 2020.

Building on existing analysis surrounding energy efficiency potential, renewable energy development, and other emerging policy directives, this paper aims to build consensus regarding the principal opportunities for direct emissions reductions originating within California's electricity and natural gas sectors. Its overall goal is to provide a clear overview of the technical and policy issues underlying sector-specific emissions reductions, and to set the stage for the development of a quantitative model to assess emission reduction opportunity within the sector.

While potentially expanding in the long-term, electric and natural gas emission reduction opportunities within the AB32 timeframe are bounded by economic, technological, and operational feasibility. The interaction of these constraints makes answering key policy questions regarding the appropriate level of emissions reductions responsibility to be assigned to the sector a complex analytical challenge. Accordingly, the Public Utilities Commission has engaged Energy and Environmental Economics, Inc (E3) to utilize production simulation and other modeling tools to assess these constraints and the relative cost-effectiveness of achieving GHG reductions within the sector.

The modeling effort has commenced and will proceed in concert with the Commissions' continued investigation of emission reduction measures. Resultant analysis is expected to be included as part of the ultimate joint Commissions' recommendation informing the development of ARB's Scoping Plan anticipated by January 2009.

2. Overview of Electric and Natural Gas Sector Emissions

The electricity and natural gas sectors account for a major share of California's GHG emissions. According to ARB's draft California Greenhouse Gas Inventory, total

generation to serve CA electric load produced 124 million metric tons of carbon dioxide equivalent (MMt CO2e) in 2004 (the latest year for which verified numbers are available. Natural gas use (exclusive of consumption for the purposes of electric generation) produced 52 MMt CO2e in 2004.[1] Considered together the electricity and natural gas sectors account for approximately 30 percent of statewide emissions, and the largest share of California emissions, outside of the transportation sector.

2004 California GHG Emissions (in million metric tons of carbon dioxide equivalent)		
Source	**Emissions**	**% of total:**
Electric Sector	**123.92**	**24.8%**
Central-Station Generation	100.10	20.1%
Imported Electricity	68.84	13.8%
Specified Imports	33.48	6.7%
Northwest	0.53	0.1%
Southwest	32.93	6.6%
Unspecified Imports	35.36	7.1%
Northwest	8.37	1.7%
Southwest	26.99	5.4%
In-State Power Plants	31.25	6.3%
Merchant Owned	25.80	5.2%
Natural gas	24.13	4.8%
Other Petroleum Products	1.30	0.3%
Geothermal	0.307	0.1%
Utility Owned	5.45	1.1%
Natural Gas	5.40	1.1%
Other Petroleum Products	0.05	0.0%
Geothermal	0.027	0.0%
Combined Heat and Power (CHP) Facilities[2]	22.46	4.5%
Electric	12.15	2.4%
Industrial	9.49	1.9%
Commercial	0.83	0.2%
SF6 from Electric Transmission and Distribution	1.029	0.2%
In-State	0.669	0.1%
Out-of-State	0.360	0.1%
Natural Gas Sector	**52.41**	**10.5%**
Transmission	0.67	0.1%
Fugitive Emissions	1.35	0.3%
End User Combustion	50.38	10.1%
Manufacturing and Construction	9.79	2.0%
Commercial/Institutional	13.18	2.6%
Residential	26.68	5.3%
Agriculture	0.73	0.1%
Statewide Gross GHG Emissions	499.06	100.0%

Source: ARB *Draft California Greenhouse Gas Inventory 8/22/07, http://www.arb.ca.gov/cc/ccei/emsinv/emsinv.htm*

1 The natural gas sector, as defined in the amended scope for this proceeding, is described in D.07-05-059. http://www.cpuc.ca.gov/word_pdf/FINAL_DECISION/68285.pdf

2 Includes all generation from CHP facilities in all sectors exported to the grid for general use, and excludes useful thermal output from industrial and commercial CHP installments.

Examining the relative magnitude of GHG emission from various sources across this inventory provides an illustrative view of where emission reduction efforts will need to focus, and potential constraints in emission reduction pathways.[3] For instance, while out-of-state power accounts for the majority share of GHGs associated with California's electricity use, the ability of unilateral California policy to impact the generation, particularly the unspecified portion, of that power is limited for a number of reasons, presenting a fundamental challenge to achieving large-scale GHG reductions from the electric sector in a cost-effective manner.

Projected growth in energy demand poses additional challenges to achieving sustained emission reductions within the respective sectors. The Energy Commission's most recent California Energy Demand 2008-2018 Staff Revised Forecast projects total load to continue to grow at approximately 1.2% annually to over 345,000 GWh by 2020. Similarly, natural gas demand is forecast to approach 14,000 MM Therms.[4] Both demand forecasts include the reductions in demand from energy efficiency programs considered to be committed.

Reconciling increasing demand for affordable and reliable electricity and natural gas supplies with the need for substantial reductions in GHG emissions poses an unprecedented challenge for the electric and natural gas sectors. While over the past thirty years California has committed considerable resources towards energy efficiency and the build-out of clean generation, overall GHG emissions have continued to rise steadily in California. Reversing the upward trend in emissions and achieving meaningful emissions reductions will require a robust policy framework to achieve reductions in a cost-effective, timely manner.

3. Reducing GHG Emissions from the Electricity and Natural Gas Usage

The principal near-term opportunities for reducing GHG emissions include increased low-carbon generation on the grid, increased energy-efficiency at the end user level, as well as broadened penetration of clean distributed generation. Given that California has already instituted aggressive policy on many of these fronts, the issue of concern in the context of AB32 is two-fold: where will current policy leave the electric and natural gas sectors in terms of GHG emissions, and what is the feasibility of further emissions reductions within the 2020 timeframe.

This section attempts to provide first a brief summary of relevant policy efforts in place affecting emission reductions from California's electricity and natural gas sectors, then a discussion of potential sources of emissions reduction above current policy.[5]

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[3] While single year numbers provide an illustrative view into the magnitude of electric and natural gas sector emissions from their various sources, it is important to bear in mind, for the sake of policy design, that emissions, particularly within the electricity sector, are subject to substantial year-to-year variation, due to variations in the supply of hydroelectricity available to be deployed to meet load within a given year.

[4] *California Energy Demand 2008 - 2018: Staff Revised Forecast*, CEC-200-2007-015-SF, October 2007. http://www.energy.ca.gov/2007publications/CEC-200-2007-015/CEC-200-2007-015-SF.PDF

[5] While the focus of this paper is on the implementation of emission reduction measures within the electricity and natural gas sectors, it is important to recognize that a number of emission reduction strategies in other sectors will impact the electric sector, some to a significant degree. Emission reduction

3.1 Existing Control Measures

Considering GHG reduction measures within the electric and natural gas sectors necessarily entails bringing together a host of efforts which have been underway in California for many years. Although not all of these measures have been directly motivated by climate concerns, they nonetheless contribute to the policy goal of minimizing GHG emissions associated with electricity and natural gas provision. Many of these control policies have been focused on load-serving entities (LSE), and among them principally investor-owned utilities (IOUs), which account for nearly 70 percent of the delivered electricity in the state.

- ***IOU Energy Efficiency Programs and Targets.*** Current efforts to improve end-use energy efficiency (EE) throughout California center around electricity and natural gas savings targets set by the Public Utilities Commission to be met by IOUs through annually funded programs. Savings targets for IOU EE programs, adopted September 2004, which run through the year 2013, were designed to capture on the order of 70% of the economic potential and 90% of the maximum achievable potential for energy savings identified for the ten-year period.[6] The Public Utilities Commission recently adopted a "risk-reward mechanism" to bolster incentives towards achieving these targets. Under the new framework, IOUs earn an increased return on EE investment if they achieve at least 85% of their EE target, or face economic penalties if they achieve less than 65% of the EE target.[7]

- ***Building Codes and Appliance Efficiency Standards***. Complementing utility demand-side management programs, efficiency codes and standards for new buildings and appliances have played a central role in California's EE efforts. In 2004 and 2005, the Energy Commission adopted significant revisions to its appliance standards and Title 24 building standards, respectively. The appliance standards are expected to save about 940 GWh in the first year of life of the covered equipment, whereas first-year savings from the building code changes have been estimated at 485 GWh. In both cases, annual savings are expected to increase as turnover in building and appliance stocks progress.

- ***Renewable Portfolio Standard (RPS)***. In 2002, SB 1078 established California's RPS program, requiring IOUs to increase the share of renewables within their portfolios to 20 percent by the year 2020. In 2006, under SB 107, the program was accelerated to require achievement of 20 percent by 2010. IOUs are required to contract for additional renewable generation each year through a solicitation process overseen at the Public Utilities Commission. On top of current renewable generation, forecasts show that IOUs are more or less on track to comply with

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measures under consideration within the transportation sector, in particular, represent the largest such potential cross-sector transfer of emissions.

[6] CPUC Decision 04-09-060. Go to: http://www.cpuc.ca.gov/word_pdf/FINAL_DECISION/40212.pdf

[7] CPUC Decision 07-09-043. Go to: http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/73172.htm

RPS requirements through the 2010 target dates.[8]

- ***California Solar Initiative***. On March 2, 2006, the Public Utilities Commission opened a proceeding to develop rules and procedures for the California Solar Initiative (CSI) and to continue consideration of policies for the development of cost-effective, clean and reliable distributed generation (DG). The California Solar Initiative (CSI) is designed as a market transformation program, to initiate the development of a self-sustaining market for rooftop PV in California. Previous customer generation programs, such as portions of the Public Utilities Commission's Self Generation Incentive Program (SGIP) and the Energy Commission's Emerging Renewables Program have been folded into the development and implementation of the CSI. The Public Utilities Commission oversees solar installments on existing homes within the IOU service areas, the Energy Commission oversees installments in new homes within the IOUs service area, while POUs oversee all installments in POU service areas. The program target is for the installation of 3,000 MW of new distributed solar generation by 2016. Compared against recent analyses of economic potential for PV installation, this goal is widely-viewed as aggressive.[9]

- ***Self-Generation Incentive Program.*** As mentioned above, the Public Utilities Commission still oversees the portion of the SGIP that includes clean distributed generation technologies other than solar, including some small-scale wind and fuel cell applications. SGIP provides dollar per watt incentive rebates to a number of DG technologies including small-scale photovoltaic and wind, fuel cells, and microturbines.

- ***IOU Procurement Adder***. In April 2005, the CPUC adopted a rule requiring investor-owned utilities to use a GHG adder for long-term resource procurement. IOUs are required to add to each bid a dollar value (minimum of $8 and up to $25 per ton) reflecting the amount of GHGs that would be emitted by a generating unit under the terms of a contract. While the Emissions Performance Standard now serves as a more binding control over GHG content of LSE procurement, the GHG adder continues to encourage appropriate ordering of low-GHG resources for the procurement of all generation which clears the EPS.

- ***Emissions Performance Standard (EPS)***. In Phase I of this proceeding, a facility-based emissions performance standard applying to all new generation and long-term procurement contracts was established, which prohibits California retail electricity providers from new investment in generation sources emitting GHGs at a rate greater than 1,100 lbs/MWh. In effect, the regulation restricts utilities from buying or signing contracts of longer than five years with new baseload coal plants and other high-emitting resources.

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[8] The Progress Report of the California Portfolio Standard, CPUC Report to the Legislature, July 2007, reports that IOUs are on target. However the IOUs' own procurement plans forecast achievement of 20% not in 2010 but 2011, or in some cases 2012.

[9] Navigant Consulting, April 2007, *"California Rooftop Photovoltaic (PV) Resource Assessment and Growth Potential by County Report,"* prepared for PIER.

3.2 Further Potential

Existing control measures within the electric and natural gas sectors are aggressive and may well capture a substantial portion of the low cost GHG measures available between now and 2020. However, depending upon the allocation of statewide emissions reduction responsibility allocated to the sector by ARB, it may be necessary to implement emissions reductions measures beyond what is currently under way.

Potential sources of additional reductions could include:

- Additional energy efficiency (beyond the currently targeted levels)
- Increased renewables (beyond currently targeted levels)
- Increased Combined Heat and Power (CHP)
- Environmental Dispatch
- Repowering and New Build with Low Carbon Technologies
- Increased conventional non-carbon resources

For each of these resources, it will important for planning purposes to characterize the following:

- the realistic resource potential,
- the market and reliability effects of increased reliance on those resources,
- what policy means might best accelerate deployment.

This section attempts to provide only a summary of the emissions reduction opportunities within California's electricity and natural gas sectors above current policy, and a preliminary discussion of these details.

3.2.1 Additional Energy Efficiency (Beyond Currently Targeted Levels)

IOU EE targets extending to 2020 are currently under development. These goals will likely be comparable in terms of degree of savings targeted, as those currently in place. While levels of EE savings exceeding current targets may be possible, capturing such savings by way of voluntary incentive programs of the sort typically run by utilities may become more difficult, as achievement of existing goals themselves will require unprecedented rates of program success and measure implementation.[10]

Instead, additional energy efficiency may need to come through newly innovative means, both in terms of technology development and delivery mechanisms. As one example, the Public Utilities Commission and Energy Commission have begun to examine the potential energy savings associated with water-use efficiency measures. In addition, new tools such as "white tags" may hold some potential in helping to overcome basic market

[10] It bears mentioning that cost-effectiveness as defined under the current Public Utilities Commission regulatory framework refers to how a given measure compares to a calculated avoided cost for a utility. Under a regulatory framework set by an overarching limit on GHG emissions, cost-effectiveness of a given measure would instead be defined by how it compares to an alternative means of reducing emissions to meet one's obligation. Under this framework, the margin of cost-effective EE measures could potentially be significantly expanded.

failures (e.g., principal-agent problems) that currently inhibit realization of cost-saving EE improvements. These improvements have the potential to improve utilization of EE as a resource in meeting emission reduction goals.

3.2.2 Additional Renewables (Beyond Currently Targeted Levels)

As existing RPS goals within the 2010 timeframe are also considered to be aggressive, the discussion surrounding 'additional renewables' in the context of GHG reductions under AB32 primarily concerns renewable development beyond the year 2010. While the Energy Action Plan (EAP) adopted by the Public Utilities Commission and the Energy Commission, and endorsed by the Governor, suggests state policy to increase renewables to 33 percent by 2020, specific targets have yet to be set. Whether such penetrations are mandated through an accelerated RPS or not, it is widely accepted that increased procurement of renewable energy on the scale anticipated by the EAP, will be a central component of achieving the level of GHG reductions required under a GHG cap covering the electric sector.

A number of resource assessments confirm renewable resource availability on the order of what would be required to achieve renewable penetrations upwards of 30 percent.[11] Particularly in the case of wind and solar thermal, raw resource potential is virtually unlimited across the Western Electricity Coordinating Council (WECC). The key issues remaining with respect to increasing penetrations of these resources are transmission interconnection, system impacts of integrating high percentages of intermittent resources into the grid, and costs.

As most of the undeveloped renewable resource potential tends to be in remote areas, significantly increasing California's share of renewables policy goals will require rapid development of new renewable resource zones throughout the state and possibly in adjoining states, and the construction of new transmission infrastructure to deliver energy from those renewable resource areas to load centers. In addition, the resource adequacy requirements imposed upon LSEs through various decisions in R.05-12-013 and its predecessor rulemakings require LSEs to procure resources within local areas determined by the CAISO. These requirements, intended to satisfy reliability standards, may conflict with preferences for remote generation resources, and resolution of the conflicts could require significant transmission system upgrades to reduce the need for local capacity. The Public Utilities Commission and Energy Commission have launched a number of initiatives to facilitate proactive deployment of transmission infrastructure to access renewable energy resources for California, the most recent of which, California Renewable Energy Transmission Initiative, is designed to identify the transmission projects needed to accommodate these renewable energy goals, support future energy policy, and facilitate transmission corridor designation and transmission and generation siting and permitting.[12]

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[11] California Energy Commission, 2005, *Geothermal Strategic Value Analysis* Draft Staff Paper CEC-500-2005-105-SD; California Energy Commission, 2005a, *Strategic Value Analysis – Economics of Wind Energy in California* Draft Staff Paper CEC-500-2005-107-SD; Center for Resource Solutions, 2005, *Achieving a 33% Renewable Energy Target*, for CPUC, November, 2005.

[12] See: http://www.energy.ca.gov/reti/index.html

As some renewable generation is intermittent and variable in nature, increased penetrations of these resources imposes cost on the electricity system beyond basic resource costs, because the output of other generators must be varied in response to the fluctuation in renewable generating output in order to maintain a system frequency within acceptable levels. This cost is very small when intermittent generators make up only a fraction of the total generation in a control area, and the variations can be compensated for by very small changes in the output of generators that are already on line. However, the costs grow as more and more intermittency is introduced into the system. As wind penetrations become larger, balancing generation supply with customer load may require simultaneous build-out of highly dispatchable generation. Improved storage technology may also provide a means to incorporating intermittent renewables into the system.

Each of these constraints translate into additional costs associated with significantly expanded renewable development. The ultimate speed and degree to which existing renewable resource potential is harnessed will be driven by how the costs of renewables compare with those of conventional resource and energy efficiency options, under increasingly stringent GHG policy constraints.

3.2.3 Increased Combined Heat and Power Penetrations

By capturing waste energy, Combined Heat and Power (CHP) installments improve generation efficiency and displaces the need for central station generation. Attendant with the reductions of energy use come reductions in GHG emissions, though the degree of carbon savings will depend on the technology and fuel used in the CHP unit and on the alternatives displaced.

While CHP units already provide 9.2 GW of capacity within California, there is likely significant potential for installation of new facilities at appropriate sites. The Energy Commission as part of the 2005 Integrated Energy Policy Report recently conducted an assessment of the market penetration potential of CHP in California[13], estimating a base case penetration of nearly 2,000 MW of new CHP by 2020, and a High Deployment Case of 7,340 MW by 2020.

Removing market barriers and disincentives to the installation of CHP units will be essential to achieving the outer bounds of CHP market potential. Processes are underway to alter rate design and market rules as a means to removing disincentives and improving CHP penetration within the state. Moreover, a GHG policy that accurately accounts for the emissions benefits of CHP installations could help provide enhanced incentives for beneficial CHP investments.

3.2.4 Environmental Dispatch

While in the short-term the generating resources available to meet demand are relatively fixed, if emissions costs were to be incorporated into operating costs of a facility, dispatch may change to reflect a new merit order. Low-emitting resources may operate

[13] Assessment of California CHP Market and Policy Options For Increased Penetration, California Energy Commission, Publication #CEC-2005-060-D, April 2005

more frequently, and high-emitting resources less frequently, minimizing the emissions output of given set of generating resources.

The realized benefit of such environmental dispatch will depend on a number of factors, including, in significant part, the price differential between the most carbon intensive components of the resource mix and generation on the dispatch margin, as well as the level at which emission cost is valued. Within this proceeding, a number of parties, citing the significant cost differential between peaking gas generation and baseload coal generation, have suggested that GHG policy within CA will be unable to compel a change in the dispatch order such that the most carbon-intensive generation serving California load becomes the marginal resource, and eligible to be displaced through environmental dispatch.[14]

The third addendum to the CEC Scenarios Analysis, released September 2007, provided the first analysis of impacts of a carbon price on WECC-wide dispatch results. WECC-wide GHG emissions decreased incrementally as the price of carbon was ramped up. On the base case scenario reflecting current penetrations of efficiency and renewables, GHG emissions decreased on average by 1, 3, 10, and 15 percent in the $10/ton, $20/ton, $40/ton, and $60/ton levels, respectively. In the cases which reflected aggressive penetrations of efficiency and renewables, emissions decreased on average by 2, 7, 16, and 20 percent in the $10/ton, $20/ton, $40/ton, and $60/ton of carbon dioxide cases, respectively. Across all cases, California emissions from local generation increased, while carbon dioxide from remote generators attributed to California and carbon dioxide emissions from California imports decreased, reflecting the displacement of GHG-intensive generation located outside California by California-located lower-GHG generation. In addition, starting in the $40/ton carbon case, an increase in gas-fired generation in the rest of WECC is noted, which contributes to the displacement of even more GHG-intensive generation.

3.2.5 Low Carbon Repowering and New Power Plant Construction

Given that the capacity for GHG policy to favorably impact dispatch decisions at reasonable cost is limited, and highly sensitive to uncertain variables (i.e. natural gas prices), the greatest potential for achieving emissions reductions by way of price incentives imposed by a GHG cap comes in the form of investment incentives for the repowering or construction of new generation that produces lower or no emissions.

Due to changing air-quality regulations, and cost concerns, many of California's generating facilities shifted in the mid-1980s from fuel oils to natural gas. As a result the remaining fuel-switching options are somewhat limited. Even so, as older facilities reach then end of their design lives and face repowering choices, opportunities may exist for new generation technologies to allow efficiency gains and emissions reductions. A number of such technologies are under development which target increasing the capacity

[14] SCE first seller comments at p.26; PG&E first seller comments at p.20; WRTPF/AREM First seller comments at p.1; See also Niemeyer (2007) in Public Utilities Fortnightly.

and efficiency of existing conventional generation facilities.[15] Many such technologies are early stage and the timeline to commercialization remains unclear.

Similarly, coal integrated gasification combined cycle (IGCC) and coal IGCC with carbon capture and sequestration (CCS), are new generating technologies that have the potential to reduce GHG emissions while continuing to permit the use of an abundant and inexpensive fuel. Coal IGCC has a very limited commercial track record, with only four demonstration units in commercial operation worldwide. CCS has no track record at all in commercial operation, and faces significant scientific and technological challenges, particularly with regards to the viability of long-term storage of CO2 in geologic formations. Nonetheless, the attractiveness of these technologies is apparent when considering the prospect of a new power generation fleet dominated by conventional coal.

As the likely rate of deployment of geologic CCS is probably too slow for consideration of this technology in policy decisions over the short-term through 2020, it is not examined in detail within this paper. Over the longer term, to 2050, geologic sequestration within California and the WECC region will surely be incorporated into any evaluations to understand how policy can achieve the much lower 2050 GHG goals while continuing to provide power at the lowest possible cost to Californians. A recent Energy Commission staff report offers a first step at this.[16]

3.2.6 Conventional Non-Carbon Resources

A less-discussed means to achieving emission reductions from the electric sector is to increase the share of conventional non-carbon resources, which do not qualify under California's RPS, in particular, large hydroelectricity and nuclear power. These resources are largely excluded from the current discussion due to limitations on their expansion throughout the state: a 1985 California law prohibiting the construction of new facilities, in the case of nuclear; and a general acceptance that most of the cost-effective large hydroelectric sites have been developed throughout the state.[17] However, due to their baseload and low-emission resource characteristics, these resources may warrant consideration in the context of longer-term GHG reductions. To the extent such examination results in policy changes, any new resource additions are highly unlikely before 2020.

3.2.7 Biomethane

While it is widely the case that emissions reductions within the natural gas sector stem from demand-side investments, the replacement of fossil-derived natural gas stocks with

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[15] See, for instance, CARB Scoping Process submittal on Simplified Combined Cycle technology: http://www.arb.ca.gov/cc/scopingplan/submittals/electricity/ghg_reductions_from_scc_technology.pdf

[16] *Geologic Carbon Sequestration Strategies for California: The Assembly Bill 1925 Report to the California Legislature*, September 2007. http://www.energy.ca.gov/2007publications/CEC-500-2007-100/CEC-500-2007-100-SD.PDF

[17] It bears mentioning however, that recent E3 analysis identified 221 MW at 36 small hydro sites in California, and 514 MW at 95 small hydro sites in the rest of WECC. For large hydro sites, the filtered list includes 440 MW at 5 sites in California, and 2003 MW at 8 sites in the rest of WECC. See E3's Issue papers.

biomethane offers an opportunity to realize supply-side emission reductions within the natural gas sector. Biomethane is natural gas produced by "upgrading" biogas to improve the heating value and to remove impurities. By eliminating the net CO2 emissions that would otherwise be emitted from burning natural gas, and by preventing the release of methane during the extraction and processing of natural gas, the substitution of natural gas supply with biomethane may yield valuable cross-sector emission reductions. The CPUC's role in determining biomethane interconnection rules and rates can have significant bearing on the investment environment for this emission reduction measures.

4. Prior Assessments of Electric Sector Reduction Potential

The Public Utilities Commission's current analytical effort benefits from two previous analyses which have laid substantial groundwork in estimating the overall potential of California's electricity sector to achieve emissions reductions: the Climate Action Team (CAT) report,[18] and more recently the Energy Commission's Scenarios project.[19]

The CAT report, released March 2006, prior to the passage of AB32, provided the first public state-level analysis of emissions reductions on a sector by sector basis. Largely based on prior analytic work by the Tellus Institute, the CAT report identifies the electricity sector as a significant source of emissions reductions, delivering over 60 MMt CO2e of emissions reductions by the year 2020, through the implementation of increased energy efficiency measures, renewable energy generation, and an electric-sector carbon policy.

For CAT's analysis, each measure's emission reduction potential was evaluated by estimating total GWh the measure will impact and applying an assumed avoided emissions rate. The expected emissions reductions from a given measure are highly sensitive to this assumed rate. For instance, the recent update to the CAT's analysis utilizes a lower avoided emission rate to reflect the elimination of coal as a marginal resource to meet new demand by out-of-state generation (as a result of the Emissions Performance Standard). As a result, the respective emission reduction numbers for principal electric sector actions are substantially diminished from the original estimates.[20]

Comparison of March 2006 and September 2007 CAT Results for Electric Sector (in million metric tons of carbon dioxide equivalent)		
	2020 Emission Reductions	
Measure	**Original**	**Update**
Accelerated RPS to 33% by 2020	11	8.2
IOU Additional Efficiency Programs	6.3	5.6
IOU Existing Efficiency Programs	8.8	3.7
Appliance Efficiency Standards in place	5	4.5
Building Efficiency Standards in place	2	2.1
California Solar Initiative	3	0.9

[18] California Environmental Protection Agency, March 2006, *"Climate Action Team Report to Governor Schwarzenegger and the Legislature"*

[19] California Energy Commission, June 2007, *"Scenario Analyses of California's Electricity System: Preliminary Results for the 2007 Integrated Energy policy Report – Staff Draft Report"*

[20] Climate Action Team, September 2007, *"Updated Macroeconomic Analysis of Climate Strategies Presented in the March 2006 Climate Action Team Report – Public Review Draft"*

IOU Electric Sector Carbon Policy	2.7	TBD
IOU Combined Heat and Power Initiative	4.4	TBD
Building Efficiency Standards in progress	TBD	(n/a)
Appliance Efficiency Standards in progress	TBD	(n/a)
Comprehensive Municipal Utility Carbon Programs	(n/a)	18
Municipal Utility Carbon Policy	9	(n/a)
Municipal Utility RPS	3.2	(n/a)
Municipal Utility Efficiency Programs	5.9	(n/a)
Total	*61.3*	*43*

While the CAT report provided an indicative early-stage assessment of where major gains in emission reductions from the electric sector may be achieved, attaining these goals is substantially more complex in practice. The implementation of emission reduction measures is tied to critical attributes of electric systems, such as the need for adequate and available power supplies at all times and at all places as needed to meet demand requirements throughout the region. These constraints are likely to temper the extent to which resources such as energy efficiency or renewables may substitute for a conventional resource in high penetration.

The Energy Commission's Scenarios Project picks up where the CAT report left off, attempting to improve the rigor of the assessment through the utilization of detailed system modeling. In particular, the Scenarios Project analyzed the implications of varying degrees of preferred resource penetration within California and the Western Interconnect, out to 2020, assessing the resource adequacy implications of significantly altering California's generation mix, as well as local capacity requirements, and necessary transmission to accompany each scenario. By attempting to prepare resource plans that assess both California-only and WECC-wide variants, the Energy Commission study revealed insights and dynamics that had not previously been analyzed.

Preliminary results from the Scenarios Analysis were released in June 2007. The findings confirmed that increased penetration of preferred resources reduces greenhouse gas emissions significantly even when dispatchable resources to assure reliability are taken into account. However, the results also illuminated the dampening effect reliability requirements are likely to have on emission reduction actions. While the more aggressive cases involve approximately 11,000 MW of dependable "preferred" capacity by the year 2020, the model found only 3,000 MW of conventional generation backed out of the resource mix, after maintaining those resources needed to satisfy resource adequacy and local reliability requirements. Relatedly, despite major penetrations of energy efficiency, rooftop PV, and supply-side renewable generating technologies, dispatch of coal generation in the results from all cases fluctuates to a very limited degree. Largely as a result of this finding, additional analyses were undertaken to evaluate the effect of a carbon adder or carbon tax on the dispatch of coal generation. As referenced earlier in this paper, the incorporation of a carbon price into dispatch decisions did materially alter resource mix and WECC-wide emissions.

The Scenarios' results can be examined from two alternative perspectives. From the vantage point of electricity sector GHG emissions from power plants located within California, even under the most aggressive scenario of energy efficiency and renewable

penetration examined, the electric sector's emissions are not returned to 1990 levels. The combination of aggressive energy efficiency and renewables comes close. From the vantage point of AB32, that is California's responsibility for GHG emissions (California-located power plants, remote power plants owned or under long-term contract to California LSEs, and short-term market purchases), then the results show that several different scenarios or less aggressive combinations of the scenarios would be sufficient to satisfy the 2020 requirements of AB32.

By design, the Scenarios Analysis did not specify particular policy actions toward achieving preferred resource penetration. The analysis to be undertaken by E3 in this proceeding will be in some ways a marriage of these two approaches. Like the Energy Commission's Scenarios Analysis, we will employ a production-cost model to examine actual physical, economic, and institutional constraints and interactions associated with our objectives in a detailed fashion. However, like the CAT approach, we will consider the specific steps towards achieving our goals of preferred resource penetration, for the sake of designing a robust set of expectations for the sector upon which to base policy decisions made in the context of AB32 implementation.

5. Conclusion

The policy means that will be utilized to realize incremental reduction potential above existing control measures, has yet to be decided. Specifically, the question remains of whether or not a cap and trade program will be implemented as part of AB32 implementation within the electric sector. A few points regarding sector-specific emission reduction opportunities explored in this paper may provide insight into the tradeoffs in considering that decision.

First, it is clear that existing control policies, provided targets are met, will deliver the lion's share of emissions reductions available from the electric and natural gas sectors. However, it also bears mentioning that existing control measures focus mainly on IOUs, and have little binding control on other types of LSEs throughout the state, such as publicly-owned utilities. Although these LSEs have been required to develop renewable and EE goals, they remain largely self-regulating under state law and thus not bound to compliance. As such, existing targets set for such entities may be inherently less reliable, however well-intentioned. Expanding the scope of GHG regulation under a statewide cap and trade program to cover other LSEs not under direct regulation by the Public Utilities Commission, would be natural extensions of a comprehensive GHG control policy for the electricity and natural gas sectors.

It is important also to note that existing regulatory control measures allow absolute emission levels to rise even while the program reduces emissions relative to business as usual levels. To meet AB 32's limit, however, California must reduce its absolute emissions. One option is for the mandatory levels of existing regulatory control measures (such as energy efficiency and RPS) to be increased. Another option is for a cap and trade program to supplement other policy tools in-place by providing a backstop in case the reductions from existing control measures do not fully materialize as expected.

A cap and trade program would likely provide a relatively small incremental portion of the overall emission reductions needed to meet the 2020 limit, above existing control

measures. Further analysis is needed to determine the level or range of incremental benefits of a cap and trade system beyond existing or augmented regulatory control measures. As many of the opportunities identified on the outer margin of potential emission reduction measures are in early stages of technological development, any GHG framework's ability to stimulate innovation is particularly valuable for capturing these potential reductions. By providing an economic incentive to exceed compliance with existing regulations where possible, a cap and trade program can spur innovation to pursue potentially cost effective opportunities outside the realm of existing control measures. A key question for policymakers will be where to draw the line between regulatory control measures and the potential market-based cap and trade program.

(END OF ATTACHMENT A)